Electrical System Review – City of Norway Electric System

City of Norway Utilities

Norway, Michigan

SEH No. NORWY0401.00

February 2004

February 9, 2004

RE: City of Norway Utilities
Electrical System Review – City of Norway Electric System
Norway, Michigan
SEH No. NORWY0401.00

Mr. Joe Pickart, Electric Supervisor
City of Norway
915 Main Street
PO Box 99
Norway, MI 49870-0099

Dear Mr. Pickart:

Enclosed is the Electrical System Review – City of Norway Utilities Electric System. The report represents the estimated performance of the electrical system with respect to overcurrent coordination, contingent switching capacity, power factor and service voltage levels within the system. Additionally the report presents a proposed Construction Work Plan (CWP) aimed at solving the issues identified in an economically viable manner. If the CWP if followed, the City of Norway Electric Utility will double its present load-serving capability positioning the Utility to serve its customers well into the 21st century.

Sincerely,

David W. Krause, PE
Senior Power Engineer

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Electrical System Review – City of Norway Electric System

City of Norway Utilities
Norway, Michigan

Prepared for:
City of Norway Utilities
Norway, Michigan

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Executive Summary

There are several electrical system issues regarding the performance of the City of Norway Utilities (NU) Electric System. These issues include:

Normal Equipment Capacity

Measurement of 2003 equipment loads demonstrates equipment loaded over its nameplate ratings on four of the six substations. This condition contributed to two significant outage events during summer 2003 conditions and reduces the expected life of that equipment.

Supply Voltage Levels

Simulation of the system using 2003 measured loads and all generators in service indicates low service voltage levels on four of the six substations. Two of these simulations were verified with actual field measurements. The equipment helping control service voltage levels (voltage regulators) reaches its maximum compensation level on four of the six substations. This condition occurs on a daily basis as indicated by recorders attached to the voltage regulators.

Contingent Capacity

The 2003 summer peak load was approximately 7.5 MVA. With this load level and the associated distribution of loads on the existing substations, the potential exists for extended outages upon failure of certain pieces of infrastructure. Specifically:

- Loss of the We Energies source or equipment at the Main Substation results in a total system outage until repairs can be made.
- Failure of a transformer on any of the six substations or three stepdowns results in outages until repairs can be made or replacements installed. Each substation represents approximately 1/12th or 8% of the total system load, roughly 250 customers. The stepdowns serve roughly 15 customers each.
- Loss of a voltage regulator on any of the six substations results in low service voltages until a replacement can be installed.
- There is presently no replacement in stock for a failure of the Ground substation serving the southwest portion of the City.

Miscoordination Between Overcurrent Devices Within the Electric Distribution System

An electrical fault is an event in which electric current flows in un-intended paths. Faults are caused by such things as:

Electrical equipment failure (age and condition or contamination)

Animal contact

Lightning

Construction damage

Public damage

Human errors such as operating errors, personnel contact with energized equipment or dropping parts/tools onto energized equipment.

Electrical currents flowing in fault conditions can be very large in magnitude generating tremendous amounts of heat. Faults can result in equipment damage/destruction, building fires, even personnel injury or death.

The electrical system should be designed to minimize the scope of damage associated with faults by interrupting service to the circuit once a fault occurs. It is also desirable to design the system so ***only the faulted portion*** of the electrical circuit is interrupted when the fault occur. This minimizes the scope of the outage resulting from the fault by shutting off power to a minimum number of users.

Miscoordination occurs when the device closest to the fault does not interrupt service, instead another device does. Miscoordination is typically caused by improperly sized fuses. As a result of miscoordination, faults on laterals protected by fuses have the potential of causing outages to the entire system. This increases the number of customers out of service and lengthens the duration of outages because the responders do not have adequate information to know where the fault is located.

Additionally, there are many laterals not presently fused. Faults on these laterals will cause the feeder breaker to interrupt the fault causing outages to the entire system.

If changes are not made, faults will most likely cause lengthy, wide spread outages.

Power Factor and System Losses

Billing data indicates system power factor is approximately 91% on peak. Although this number can be typical for systems of this size there are cost effective steps that can be taken to decrease the losses associated with this condition. They include the expansion of existing power capacitors and/or the installation of additional power capacitors in strategic locations. Poor power factor results in increased payments to We Energies for demand, transmission costs and energy payments due to increased system losses.

System losses range from 10-15% of the total energy consumed. This results in roughly $100,000 per year in lost revenue and is indicative of a system with undersized conductors and low system voltage levels. The changes proposed in the Construction Work Plan will improve but not totally eliminate these revenue and system losses.

Oil Spill Prevention

The EPA enacted regulations requiring utilities to provide oil spill control measures. These regulations are intended to keep oils such as transformer insulating oil from navigable waterways. The electrical substation at the Hydro project is one such installation governed by the EPA. Based on the regulations and the configuration of the existing substation a relocation and reconstruction of the substation is recommended providing compliance with the regulations and improving the electrical performance of the system.

Hydro Plant

A cursory overview of the hydro plant indicates additional investment is required to sustain plant operations. Significant concrete degradation is visible on portions of the structure, replacement of the remaining high-speed, vertical-shaft generator will be required and renovation of the power circuits will also benefit plant operations. Since the plant provides significant financial benefit to the City, these investments should be planned and made as part of the overall Utility management strategy.

Tools and Equipment

To run a safe, effective and efficient electric utility requires motivated employees who are properly trained and equipped. Additional investments should be made in trucks, tools, installation and testing equipment allowing the staff to perform maintenance functions and to do so in a more efficient manner.

Priority Ranking

For the purpose of this analysis, a three-step priority ranking system is used. Letter designations are added to indicate sub-priority with "A" being most critical, followed by "B", etc. within the priority list.

Priority 1 items are issues that, in the definition of the author, *"shall or must"* be corrected. They include normal equipment capacity, low supply voltage levels, public health and safety issues and rules or mandates.

Priority II items are issues that *"should"* be corrected. They include inadequate contingent capacity, system coordination/protection and tools and equipment.

Priority III items are issues that, when corrected, provide benefit to the Utility. They include power factor and system losses and financially beneficial strategies.

Solutions

The solution presented in the preferred plan consists of the construction of a new 69-24.9kV 14MVA substation with three feeders, reconstruction of the hydro plant substation using three breakers and oil containment structures, voltage conversion of rural service areas, short-term continued operation of the downtown at 4.16kV, split operation of the loop as two independent feeders and the purchase of selected tools and equipment including two new vehicles.

Costs

An immediate $55,000 is required to install voltage regulation at the existing main substation. Year 1 estimated costs of $3,210,000 should be spent to correct most of the Priority I and Priority II deficiencies. Beyond that, an additional $615,000 is suggested in the following two years completing construction of the priority needs of the distribution system. An estimated $40,000 is also recommended allowing review of the system after the reconstruction occurs and to study the feasibility of combustion generation and the potential rate relief or revenue it can provide. Funding of the construction projects should be provided by a revenue bond issuance. The studies and the immediate needs for voltage regulation should be funded from operating reserves.

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Electrical System Review – City of Norway Electric System

Prepared for City of Norway Utilities

1.0 Introduction

1.1 Purpose and Scope

This study was undertaken to identify concerns related to providing reliable electric service to customers of the City of Norway Utilities. The goals of the study are:

- Determine if selective coordination of overcurrent devices exists throughout the system.
- Determine if the system is selective regarding scope of potential outages
- Determine if adequate contingent capacity exists to restore service for major component loss.
- Determine if service voltage levels are adequately maintained throughout the system.
- List any other major issues as they arise.
- Provide solutions to the identified issues in a prioritized, multi-year plan including timing and engineering estimates of probable costs.

2.0 Background – Infrastructure

The City of Norway Utilities (NU) recognized that continuing aging coupled with slow but steady load growth is taxing their electrical system. System losses were increasing, occasional outages were large in scope due to improper sectionalizing and there were increasing indications that certain component failures could cause extended outages until repairs could be completed. Coupling these observations with the new EPA rules for oil spill containment NU requested this review of their electrical system to identify the breadth and depth of these issues.

2.1 We Energies Supply Data

We Energies owns and operates a 13.8kV, three-phase, three-wire distribution line, sourced from the ATC substation at the Paper Mill, which provides service to the City of Norway. Fault current levels are approximately 2,500 amps as supplied under system-normal conditions. This distribution line serves some We Energies customers on the outskirts of the City as well as all City served loads. Past discussions were held regarding the eventual movement of City distribution loads off this 13.8kV line to another source.

We Energies also owns and operates a 69-24.9kV distribution substation serving its rural loads in this area. This substation is located on the northwest side of the City near the Belgium Town Road. At this time, there are no ties between this substation and City lines.

2.2 City of Norway Utility - Electric System Data

NU owns and operates eight substations.

At the Main substation the We Energies billing metering, a line breaker with relay controls and a 48V DC battery supply exist to affect the interconnection between We Energies and the City. Should a fault occur on the City's system, the line breaker at this Main substation will open to isolate the City's lines from We Energies. With only one line breaker a fault causes the entire City to go out of power. The hydro plant also goes off line, requiring a manual restart once power can be restored. A new microprocessor based relay was installed in 2003 facilitating restoration of power to City loads after fault conditions on either City or We Energies lines.

Five of the six NU distribution substations use 3-250kVA single-phase 14.4kV-2.4kV step-down transformers with 3-200 amp single-phase 2.4kV voltage regulators supported by platform mountings. Fuse protection is provided on both the 13.8kV and 2.4kV sides of the transformers. These transformers are provided with no-load taps set at a nominal 13.8kV level. North and South Brown Street and Hill substations serve loads at 4.16/2.4kV, three-phase multigrounded-wye operation. Curry serves its loads at 2.4kV delta three-phase operation and suffers from inadequate electrical clearances according to the National Electric Safety Code (NESC*). Vulcan is a single-phase version of this concept serving loads at 2.4kV delta operation. Presently one of the three voltage regulators at the South Brown Substation is non-functional in automatic operation. It must be monitored and manually adjusted to provide correct service voltage levels.

There are also three independent stepdown subs which are single-phase, 13.8-2.4kV, 250kVA. They have fuses on the high and low voltage sides of the transformer however they are not equipped with voltage regulators. This is the same transformer specification used in the aforementioned five distribution substations. Presently three transformers and two voltage regulators are held as spare equipment for emergency replacement.

The Ground substation is a self-contained, 1500kVA 14.4-2.4 kV unit substation complete with an internal voltage regulator (LTC), high-side power fuses and a low-side line breaker. At this time the LTC is non-functional in automatic operation. It must be monitored and manually adjusted to provide correct service voltage levels. No spare for this substation is owned by the City.

The hydro plant substation consists of two, 5000kVA 14.4-7.2kV three-phase power transformers and pipe-buswork. There is presently no overcurrent or protective devices connected to either the hydro or line sides of these power transformers. Concrete supports for the transformers as well as security fence round out this substation. Only one of the two transformers is currently energized, it is unknown if the spare transformer is functional.

Only two of the distribution substations, North and South Brown Street, have physical wire connections between them. The remaining four substations (Hill, Vulcan, Curry, and Ground) and the three stepdowns are independent with no direct backup. As stated earlier, the hydro plant substation has an on-site spare transformer however its physical condition is unknown.

336.4 ACSR is the preferred overhead conductor for the main-line 13.8kV loop. This loop was totally reconstructed in the early 1990’s to 25kV operating standards including phase conductor spacing and line insulation levels and is presently in good operating condition. Additionally a system neutral conductor was installed in anticipation of the eventual conversion of the system to a preferred, multi-grounded wye operation. Most rural lines are #4 copper construction suffering from questionable structural integrity. Pole structural testing should be completed to ensure these installations meet NESC codes for strength.

Since the 13.8kV system is operated as a closed-loop, a fault on any portion of the approximately 11 mile long system causes an outage to the entire system. This configuration is difficult to trouble shoot as the lineworkers are not provided information regarding where the fault occurred. This results in lengthy outages.

3.0 Load Data

The summer 2003 peak can be broken into two parts, watts or real power and vars or reactive power. Power factor is a measure of the relative values of the two parts and is an indication of the efficiency of power delivery in the system. A stated in the executive summary, during the NU peak of 7.5 MVA the average power factor was 91%. This equates to a peak demand of 6.8 MW and 3.1 MVAr. NU loads for both energy and demand are growing at a modest 0.7%/year. Due to metering issues at the Main Substation and the hydro plant, the system peak demand had to be approximated.

4.0 Deficiencies

4.1 Normal Equipment Capacity

Electrical equipment capacity is mostly a function of the equipment's ability to radiate heat maintaining internal temperatures to acceptable levels. For transformers, heat beyond design levels ages the insulation within the transformer prematurely, which leads to premature failure and the need for replacement of the failed equipment. Obviously, ambient temperature of the air surrounding the equipment has an effect on the amount of load a transformer can safely carry beyond its nameplate rating. Since NU is a summer peaking utility, we must size the transformers such that they are not significantly overloaded during conditions when the ambient temperature is high. Winter loads are not as much of a concern as the air is cool providing additional heat dissipation. Short-time loadings beyond nameplate can be acceptable, especially in emergencies. Engineering guidance is recommended to assess load duration, peak load magnitude and ambient temperature.

Overloading of transformers also makes the transformer less efficient. This inefficiency in turn increases system losses and lowers supply voltage levels.

As demonstrated in Appendix A, equipment overloads exist at many substations. The summary table lists the substations, nameplate capacities, measured loads and overload percentages. For substations consisting of three, single-phase transformers banked together, the loads are stated as the largest measured per phase, and total for the entire transformer bank. Premature loss of life is anticipated for three of the six substations listed. During summer 2003 peak conditions two different transformer failures resulted in outages until a replacement could be installed. Continued operation at these load levels during summer peaks will provide increased probability of additional failures.

4.2 Supply Voltage Levels

Given the loads described in Section 3 above the system nominal voltage levels were simulated. Additionally all power transformers modeled were set at a no-load tap of 0% and We Energies service voltage level was assumed to be nominal 13,800 volts at the Main substation. Although We Energies presently has a set of voltage regulators on its 13.8kV line west of the Main substation the model does not reflect this. We Energies has informed NU that one regulator is non-functional so they have disabled the entire installation and would like to remove it from service permanently.

Normal operation of an electric system provides a nominal service voltage of 120 volts +/- 5% at the meter. This allows a range of acceptable service voltage levels from 114 volts to 126 volts on a 120 volt nominal basis at the meter. Utilization equipment is constructed based on the assumed service provision of nominal design +/- 5%. Some rural service areas allow +/- 6% and under certain emergency conditions may allow an additional 1-2% voltage deviation from nominal.

Of this voltage range, we can anticipate 2-3% drop due to the service transformers and secondary/service conductors to the customer meter. This means we need to maintain our primary system voltage level within a range of +5% to –2%, this accommodates the additional 2-3% drop in the service conductors allowing the utility to maintain 114 volts at the meter.

The maps in Appendix B demonstrate what areas of the system are at or under the –2% primary system voltage level. Black indicates acceptable performance while red indicates issues. As demonstrated there are several areas of concern. During summer peak conditions some of these projected conditions were verified by field measurements based on customer complaints and subsequent testing. The first map shows areas where primary system voltages are under 116 volts on a 120 volt basis. The second shows areas where primary system voltages are under 118 volts on a 120 volt basis.

Under normal operation up to 10% voltage drop is experienced in the primary voltage system. This does not consider the 2-3% drop in the service system to the customer meter. Coupling these issues equates to approximately 104 volts service at the customer meter. This is poor performance indicative of undersized conductors and substation transformers, lengthy feeder lines and excessive loads.

It should be noted that We Energies meets its regulatory requirements by serving NU with as low as 90% of nominal voltage. This additional 10% decrease in voltage levels would be on top of the 12-13% estimated system voltage drop resulting in an estimated 77-78% of nominal voltage service at customer locations. Although we have voltage regulators to compensate the system, they can only compensate for +/- 10%. As such even lower service voltage levels would be experienced throughout the system causing customer equipment to shut down.

4.3 Contingent Capacity

There are several concerns regarding outages and the ability of the existing infrastructure to handle increased loads upon failure of one part of the system. Examples of this are:

- Failure of a transformer on any of the six substations or three stepdowns results in outages until repairs can be made or replacements installed. Each substation represents approximately 1/12th or 8% of the total system load, roughly 250 customers. The stepdowns serve roughly 15 customers each.
- Loss of a voltage regulator on any of the six substations results in low service voltages until a replacement can be installed. In affect, low service voltage is equivalent to an outage.
- There is presently no replacement in stock for a failure of the Ground substation serving the southwest portion of the City.

Any of these events will result in unserved loads.

4.4 Overcurrent Coordination

For the purpose of this study “selective coordination” exists when there is at least 0.2 seconds (12 cycles) of time margin between series protective devices.

In order to coordinate correctly with the line breaker at the We Energies substation, relay settings were engineered for the line breaker at the Main substation. Based on those settings a maximum of a 40 amp, type T fuse should be used to coordinate with the Main substation line breaker. There are many places where larger fuses are being used. Additionally, different types of fuses such as QA, N, Coordinating and standard speed fuses have been purchased and used throughout the system.

Replacing fuses with the correct size and type will need to be done to make the system coordinate properly. These requirements also limit the maximum size substation transformer which can be used on the system to 250kVA. As such, correcting overloads can not be done by replacing the existing transformers with larger ones.

There are many laterals not connected to the main-line feeders through fuses. A fault on one of these laterals will cause the entire feeder to trip and possibly stay out of service. All laterals tapped off the main loop should be fused to protect the entire City from lateral faults.

4.5 Power Factor and System Losses

Supplying reactive power is a necessary function of a power system. It should be noted, however that the supply of reactive power increases system losses and consumes capacity, thus limiting normal and contingent operation of the system. Mitigating reactive power supply is accomplished through the installation of capacitors, either by customers who consume reactive power or by the serving utility. On NU's system, both methods are applied. Presently NU provides 1.35 MVAr worth of fixed or "full-time" reactive power supply on its system.

The method We Energies uses to meter and bill NU for demand and energy considers power factor. NU pays a penalty if its average power factor goes below 90% and gets relief if it is over 90%. The method used is an adjustment to the measured demand based on the ratio of the actual average power factor vs. the 90% goal.

As an example, if the NU average power factor is 70% and 4,000kW of peak demand is metered, We Energies would adjust the measured 4,000 kW by the ratio of 90%/70%, or they would multiply the 4,000 kW metered demand by (90/70 = 1.2857) yielding 5,142.8 kW of billed demand. At the present rate of $4/kW this poor power factor performance yields an additional $4,571.43 in demand payments to We Energies by the Utility. Additionally, since the transmission charge paid to We Energies is based on the billed demand, the base rate of $0.80214/kW transmission charge would yield an increase of (5,142.8kW - 4,000kW)*$0.80214/kW or $916.69 also paid to We Energies by the Utility.

For the same example, if the NU average power factor were 99%, the 4,000 kW metered demand would be adjusted downward by the ratio of 90/99, resulting in a billed demand of 3,636.36 kW. At $4/kW this results in a reduction of the demand component of the bill equaling $1,454.54. Additionally, this also reduces the transmission component of the bill by $291.69.

As this desire may not be practicable for customers, it is recommended that NU increase its supply of reactive power to improve the efficiency of its system. This effort will increase the power factor on peak, decrease system losses and increase service voltage levels throughout the system. Additionally increased power factor will minimize the financial penalties paid to We Energies. An estimated 1.2 MVAr could easily be added to help accomplish this loss reduction goal. Payback is less than one year.

System losses are estimated at 13% of the total system demand and are increasing as the system demand increases. The calculation of losses is based on 2002 data showing 27.7MkWh sold, 27.5MkWh generated and 5.4MkWh purchased. 1.6MkWh were sold as surplus back to We

Energies in the same timeframe thus leaving 3.6MkWh unaccounted for which is the losses in the system. At an average of $0.023/kWh (average of on and off-peak purchases) the dollar value of the energy lost is roughly $82,800 annually. To fully evaluate loss values, the value of the demand and transmission charge adders also need to be considered. The Electric Utility average demand payment to We Energies is $135,000, taking 13% of that value yields and additional $17,550 in demand/transmission charges, bringing the total to $100,350. Eliminating system losses during on-peak times presents additional opportunity as the buy-back price for on-peak energy from We Energies is $0.0454/kWh.

Losses are comprised of three components, losses in the high-voltage wires, distribution transformers and low-voltage secondary/service conductors. The plan as presented in the CWP addresses losses in the first and possibly the second components based on procurement standards for replacement transformers. Losses in the secondary/service conductors are not economically recovered from reconstruction of those facilities.

4.6 Oil Spill Prevention

As stated in the Executive Summary, the US EPA has enacted new regulations requiring utilities to develop and maintain plans for reacting to oil spills. These plans must address training, identification of potential hazards, mitigation techniques and construction of the appropriate containment structures should they be required as part of the response plan.

To avoid a significant environmental issue most likely involving the Michigan and Wisconsin Departments of Natural Resources as well as the EPA and the Fish and Wildlife Service, it is recommended that the hydro plant substation be reconstructed and relocated to higher ground. With this proposed reconstruction concrete oil containment basins for both power transformers would be installed preventing an unwanted discharge of insulating oil into the river. Should evaluation of the existing power transformers determine their life expectancy is limited, newer technologies including bio-degradable insulating oils can be explored.

4.7 Hydro Plant

There are several issues associated with the hydro plant mentioned here as placeholders for future budget consideration. They include:

- Refurbishment of degrading concrete structures
- Replacement of the #1 Generator thrust bearings
- Replacement of the remaining high-speed, vertical-shaft generator/turbine

- Security Measures and FERC mandates.
- Overcurrent device replacements/installations
- Power conductor replacements

Additionally, consideration should be given to supplemental generation such that the system could be operated in an islanded mode. In addition to this added level of reliability, the financial incentives based on a change in rate structure with We Energies from full-requirements to an interruptible rate could make this option financially beneficial to the Utility and its customers. A feasibility study is included in the CWP to allow further study of this issue.

4.8 Tools and Equipment

Continued changes in technologies coupled with updates to OSHA regulations regarding workplace safety dictates improved tooling and equipment for electric utility workers. To support the work plan, NU staff should be equipped with electric meter testing equipment, a digger-derrick capable of extensive winter operation, a bucket truck capable of use on 25kV class systems, insulation and working cover-up, digital phasing sticks, voltage regulator neutral detectors, fault indicators, and other miscellaneous tools and equipment applicable to a utility operating and maintaining a 25kV class system. These needs allow staff to maintain the existing and proposed systems. It is anticipated that construction of the major portions of the new system will be contracted out as the added costs for additional wire stringing equipment are not cost justifiable. Ergonomically correct tools will reduce the likelihood of injury and improve employee efficiency. These investments will provide payback via a reduction in contract labor to affect the work plan.

5.0 Discussion

A major factor in solving the aforementioned issues is the decision on what system voltage level the Utility should operate at. Presently there are three major options:

- Continued operation at 13.8kV delta served from We Energies
- Operation at 13.8/7.97kV wye served from a new substation.
- Operation at 24.9/14.4kV wye served from a new substation.

The availability of a 69 kV transmission line within the City limits coupled with developing independence from We Energies makes the construction of a new substation attractive. We Energies and ATC have indicated an interest in removing City electric loads from the 13.8kV delta source, improving their own reliability. Construction of a new substation and a transmission line interconnection may open additional doors for energy supply after the expiration of the existing power supply contract. Existing pricing for new substation equipment is observed to be at a 20 year low point. Coupling that with limited capacity from We Energies at 13.8kV delta and favorable interest rates makes the timing for a new substation attractive. At best, We Energies can only serve an additional 4 MW at 13.8kV before their feeder line providing service to Norway is overloaded.

Operation of a delta distribution system is problematic from a troubleshooting standpoint. Presently, there exists an electrical "ground" on the delta system which staff had been unable to locate. It was found and corrected in December as maintenance of an existing capacitor bank removed the concern. Operation of a wye system eliminates this and other issues. The existing delta system has limitations in terms of fuse sizing and fault current levels because of the interconnection, We Energies requirements and system constraints. As such the maximum service transformer size is limited to something less than typically available.

Delta systems also necessitate transformers with primary voltage windings insulated for full system voltage. Compared to the comparable wye system, use of delta results in an additional $150 per transformer installation. This cost adder consists of two-bushing transformers vs. single-bushing on a wye system and two cutouts/fuses/arresters vs. one each on the wye system. With approximately 280 transformers being affected within the scope of the CWP, the cost savings of wye vs. delta associated with transformers is over $40,000. Additionally, for every structure constructed delta there exists the added necessity of using crossarms/braces and bolts, insulators/pins and wire ties vs. the less expensive practice of single-phase wye connected pole framing using pole-top pins and only one insulator per structure. The changes allowed in construction practices will save an additional $60,000 between the Hill, Curry and Vulcan service area conversions alone.

Wye systems are the industry standard and are preferred in this case. Between the two options available, 24.9/14.4kV has slightly higher equipment costs however it is preferred for the following reasons:

- Improved performance from a voltage regulation standpoint
- 69% lower system losses as compared to the comparable 13.8kV system.
- Presence of a possible interconnection with the existing We Energies substation. This could save $150k in power transformer costs alone vs. a 13.8kV option and would facilitate timing in conversions.

- Use of the 24.9kV system allows the Utility to re-use 124 existing transformers at a cost savings of approximately $86,000.
- Transformers at the hydro substation are capable of connection to either system.
- Staff workers have the required experience for working on 25kV class systems.
- We Energies and Wisconsin Public Service have both standardized on 24.9kV construction, as such joint action/mutual aid can be structured with either utility.
- 25kV class systems operate with less fault current than their 15kV class equivalents. Less fault current can equate to lower arc-flash hazards. The arc-flash hazard standards will become an OSHA regulated safety issue in the near future for utility workers.

6.0 Solutions

The solutions presented are based on sound engineering practices and agreement between City staff and the engineer. A table summarizing the major components of the Construction Work Plan is included in Appendix C for your reference.

6.1 Preferred Plan

In summary, the preferred plan includes the following major components:

Construction of a new 69-24.9kV substation

- 10//14MVA power transformer
- Bus breaker
- Three regulated feeders
- Tie to another source or spare power transformer

Main Substation

- Install a set of the voltage regulators slated for the new substation at the existing Main Sub as a temporary measure. This will improve service voltage levels for summer 2004 peak conditions.
- Relocate breaker to hydro plant substation as the plant breaker.

Hydro plant substation

- Add plant breaker and two feeder breakers for protection
- Reconstruction/relocation of the substation

- Assess the existing transformer life expectancy
- Allows split operation of the existing loop improving reliability, restoration times and keeps the hydro generation on line for many faults.

Hill Sub

- Reconductoring main-lines to 1/0 ACSR
- Reconstruction and voltage conversion of loads
- Pole and transformer replacements as required.
- Reduces losses, eliminates service voltage concerns

North Brown Substation

- Parallel Hill Sub transformers on existing platform
- Increases capacity by 100% alleviating overload condition.
- Improves voltage regulation and decreases system losses.
- Provides contingent capacity for loss of another source
- Removal of voltage regulators on former Hill Sub.

Vulcan Sub

- Add second 250kVA transformer
- Increases capacity by 100% alleviating overload condition
- Reconductor main-line with 1/0 ACSR
- Improves voltage regulation and decreases system losses.
- Eliminates service voltage concerns

South Brown Substation

- Replace substation transformers with new 1500kVA pad-mounted transformer
- Increases capacity by 100% alleviating overload condition
- Improves voltage regulation and decreases system losses.
- Provides contingent capacity for loss of another source
- Replace failed voltage regulator with existing spare
- Tie to loads served from Ground Substation

Curry Substation

- Replace entire substation with former South Brown Substation
- Convert system to 4.16kV wye operation
- Reconductor main line to 4/0 ACSR – tie to N. Brown Substation
- Eliminates oldest equipment in system
- Eliminates code concerns regarding electrical clearances.
- Provides Contingent capacity for loss of another source

Ground Substation

- Tied to South Brown for normal load service
- Existing transformer to be used only as back up to South Brown
- Convert rural loads to main-line loop to eliminate service voltage concerns and to reduce system losses.

Power Factor

Add 1.25 MVAr worth of capacitors

- Add 150 kVAr to N. Brown, S. Brown, Curry, and Ground sub service areas. Total 600kVAr
- Add 600kVAr controlled bank on main line.
- Add 50kVAr to Vulcan substation.

Tools and Equipment

- Bid and purchase new bucket truck, new digger-derrick
- Purchase the required tools, equipment, meter testing equipment and FR clothing.

6.2 Alternates

The following alternates exist to the preferred plan. They are listed as line items which can be inserted into the Preferred plan with the appropriate adjustments made to timing.

Hill Substation

If the new 69-24.9kV substation needs to be deferred, the Hill Substation area should be converted to 13.8kV delta operation. This action corrects the low service voltage conditions and normal capacity issues presently experienced. This options costs an additional $100,000 over the preferred plan based on two-phase delta construction and dual-bushing delta transformer installations. This alternate also does not provide for increasing the capacity of the North Brown Substation.

Proposed New Main Substation and Hydro Substation

Both substations could be operated with a closed-loop as is presently the case. The estimated $40,000 in savings over the proposed plan is offset by decreased system performance and reliability. The proposed plan allows continuous hydro output even if a fault occurs on one half of the loop. This alternate would trip the hydro plant off-line in the event a fault occurs.

Curry Substation

An alternate to continued investment in 4.16kV systems would be to convert Curry to 24.9kV operation initially. This path would provide an eventual tie from the proposed downtown 24.9kV circuit to the east loop.

All remaining substations can be converted immediately to 24.9kV operation. This work, although beneficial to the customers, results in an increased rate escalation vs. the proposed plan.

7.0 Summary

In summary the NU electric system has several performance issues which should be addressed. There are several concerns surrounding contingent performance of the system and the ability to restore loads after certain equipment failures. Improved reliability and a decrease in system losses can be achieved through increasing conductor and power capacitor sizes and through changes in the overcurrent protection utilized. An estimated $3.3M in immediate needs with an additional $600k anticipated will position NU to serve its customers for years to come.

Appendix A

Summary Data

City of Norway
Electric System Overview
Summary Data

Component & Description	Capacity	Load kVA[2]	% Nameplate Loading
Summer 03 Peak Load	**7200**[1]	**7500**	**104**
North Brown Transformers	**250/750**	**271/789**	**108/105**
South Brown Transformers	**250/750**	**231/629**	**92/84**
Ground Sub Transformer	**1500**	**693**	**46**
Hill Sub Transformers	**250/750**	**310/689**	**124/92**
Curry Sub Transformers	**250/750**	**184/430**	**74/57**
Vulcan Transformer	**250**	**318**	**127**

(1) System capacity limitation is 2/0 ACSR owned by We Energies 300 amps @ 13.8kV.
(2) Load represented is individual transformer/total station load as measured.

Appendix B

Voltage Profiles

Appendix C

Construction Work Plan

Five Year Construction Work Plan
City of Norway Electric Utility
December 2003

Year	Project	Cost	Priority
2004	Purchase and install voltage regulators at existing main substation	$35,000	1A
	Design/engineering/procurement and installation costs	$20,000	
Total		**$55,000**	
1	Construct new Main substation 69-24.9kV 14 MVA	$1,200,000	1F
	Reconstruct and relocate Hydro Plant Substation	$200,000	1B
	Convert main lines to 25kV	$150,000	1F
	Reconstruct and convert Hill Sub service area	$285,000	1C
	North Brown Sub – Increase Capacity	$10,000	1G
	Vulcan Sub – Reconductor and Increase Capacity	$40,000	1D
	South Brown Sub – Replace Transformer and tie to Ground Sub	$40,000	1H
	Curry Sub – Replace and convert to 4.16kV	$45,000	1E
	Ground Sub – temp transfer loads to main-line stepdowns	$10,000	1I
	Power Factor – Add 1.2 MVAr	$30,000	3A
	Vehicles, Tools and Equipment	$300,000	2B
	Engineering/design	$300,000	
	Contingencies	$100,000	
	Replace #1 Generator Thrust Bearings	$500,000	2A
Total		**$3,210,000**	
2	Ground Sub – convert rural loads to main-line loop and eliminate transformer.	$85,000	3A
	Convert Vulcan to 14.4kV	$85,000	3B
	Hydro Structural Upgrades	$100,000	2A
Total		**$270,000**	
3	Convert Curry to 24.9kV operation – construct downtown feeder loop	$135,000	3A
	Convert Stepdowns to 24.9kV operation	$145,000	3B
	Replace Hydro Power conductors and protection	$65,000	3C
Total		**$345,000**	
4	Feasibility study – combustion generation and interruptible power supply	$20,000	3
Total		**$20,000**	
5+	Review power system study – load growth, power factor etc.	$20,000	3
Total		**$20,000**	
Sum Total		**$3,920,000**	

Appendix D

Model Output